

Alternative Fuels

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Mechanical Engineering 496ALT
Alternative Energy

March 19, 2009

California State University
Northridge

Assignments:

Reading for tonight: Chapter 7 on fuels.

Reading for next Tuesday, Chapter 10 on biofuels.

Next Thursday, March 26 will be a presentation from Bob Litwin of Rocketdyne on design of a solar thermal electric power generatin plant.

The next midterm exam will be on Thursday, April 2, covers up to and including wind power.

Wind energy homework due next Tuesday, March 24.

Outline

- What are alternative fuels?
- How do we do fuel conversions?
 - Chemical reactions and chemical energies
 - Reactor types
 - Production of liquid and gaseous products
- Policies on fuel conversion research and development
- Integrated gasification/electric power

This lecture will cover the general topics of making nonconventional fuels such as manufactured gas and liquid fuels from coal.

The following lecture will cover biomass fuels, including fuel ethanol, biodiesel, refuse derived fuels (RDF), and direct combustion of biomass fuels.

What are Alternative Fuels?

- Typically a liquid or gaseous fuel made from coal or some other source
 - React coal with steam to get liquid or gas fuel
 - Manufactured gas a common fuel prior to the widespread availability of natural gas
 - Liquid transportation fuels from coal
 - Can also make liquid fuels from gas
- Energy security may be an issue
 - WW II Germany and South Africa during apartheid
- Environmental benefits

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Alternative fuels consists of a wide range of topics including fossil fuels significantly modified from their original form. (The word significantly is meant to exclude normal refining/processing operations applied to gas, oil, and coal.) The main reason for such modifications in the past has been to convert fuels from their original form into a form that is more convenient for a particular use such as liquid fuels from coal. Recent research in this field has focused on converting fuels such as coal to improve their environmental performance.

Fossil fuel modifications are sometimes called synthetic fuels or synfuels. During the period after the 1973 oil embargo there was a large amount of research on finding a substitute for natural gas. This was sometimes called synthetic natural gas or SNG. After many joking comments about a “synthetic natural” product, the acronym SNG came to mean substitute natural gas.

The US started a synthetic liquid fuels program in 1944 as a long-term back-up measure to provide for potential future oil shortages. It has operated sporadically since then. With the discovery of large oil deposits in the Middle East in the 1950s, the program was scaled back only to be reinvigorated following the 1973 oil embargo. The program reached a peak in the early 1980s and has operated at a lower level since that time.

Most recently “clean coal” programs have sought to produce gaseous fuels at the site of electricity generating stations as a method to produce cleaner energy from coal.

Fuel Conversion Reactions

- $C + O_2 \rightarrow CO_2$ ($\Delta H_R = -394$ MJ)
- $C + CO_2 \rightarrow 2CO$ ($\Delta H_R = 171$ MJ)
- $C + H_2O \rightarrow CO + H_2$ ($\Delta H_R = 130$ MJ)
- $C + 2H_2O \rightarrow CO_2 + 2H_2$ ($\Delta H_R = 87$ MJ)
- $CO + H_2O \rightarrow CO_2 + H_2$ ($\Delta H_R = -41$ MJ)
- $C + 2H_2 \rightarrow CH_4$ ($\Delta H_R = -75$ MJ)
- $CO + 3H_2 \rightarrow CH_4 + H_2O$ ($\Delta H_R = -206$ MJ)

A negative heat of reaction means that energy is given off; a positive heat of reaction means that energy has to be added to carry out the reaction. The terms exothermic and endothermic are used to refer to reactions that, respectively, give off heat and require a heat input.

In addition to the simple effect of producing or releasing heat, the equilibrium of reactions, even if they produce heat, may require the production of high temperatures to make the reactions possible.

The basic reaction in converting coal to liquid and gaseous fuels is the reaction $C + H_2O \rightarrow CO + H_2$. Because this reaction is endothermic, there is a net energy input to make it go. The significance of the energies associated with the various reactions here can be seen by comparing them with the first reaction for the combustion of carbon.

The reaction, $CO + H_2O \rightarrow CO_2 + H_2$ ($\Delta H_R = -41$ MJ), known as the water-gas shift reaction, is used in the production of hydrogen.

Synthetic Gases from Coal

- Variety of names
 - Goal Gas, Town Gas, Producer Gas, Illuminating Gas, Blue Gas Domestic Gas, Water Gas, Carbureted Water Gas, Manufactured Gas
- Classified by heating values
 - Low Btu (50 to 200–250 Btu/scf)
 - Medium Btu (about 500 Btu/scf?)
 - High Btu (>900 Btu/scf)

Reference: <http://www.zetatalk.com/energy/tengy11a.htm>

The most complete conversion of coal or coke to gas that is feasible was achieved by reacting coal continuously in a vertical retort with air and steam. The gas obtained in this manner, called producer gas, has a relatively low thermal content per unit volume of gas (100-150 Btu/cu ft). The development of a cyclic steam-air process in 1873 made possible the production of a gas of higher thermal content (300-350 Btu/cu ft), composed chiefly of carbon monoxide and hydrogen, and known as water gas. By adding oil to the reactor, the thermal content of gas was increased to 500-550 Btu/cu ft; this became the standard for gas distributed to residences and industry. Since 1940, processes have been developed to produce continuously a gas equivalent to water gas; this involves the use of steam and essentially pure oxygen as a reactant. A more recently developed process reacts coal with pure oxygen and steam at an elevated pressure of 3.09 Newtons per sq m (450 psi) to produce a gas that may be converted to synthetic natural gas.

The most common modern process uses lump coal in a vertical retort. The coal is fed at the top with air, and steam is introduced at the bottom. The gas, air, and steam rising up the retort heat the coal in its downward flow and react with the coal to convert it to gas. Ash is removed at the bottom of the retort. Using air and steam as reacting gases results in a producer gas; using oxygen and steam results in a water gas. Increasing operating pressure increases the productivity.

Two other processes currently in commercial use react finely powdered coal with steam and oxygen. One of these, the Winkler process, uses a fluidized bed in which the powdered coal is agitated with the reactant gases. The other, called the Koppers-Totzek process, operates at a much higher temperature, and the powdered coal is reacted while it is entrained in the gases passing through the reactor. The ash is removed as a molten slag at the bottom of the reactor. Both of these processes are being used for fuel gas production and in the generation of gases for chemical and fertilizer production.

Producer gas is a mixture of approximately 25% carbon monoxide, 55% nitrogen, 13% hydrogen and 7% other gases. It is obtained by burning coal or coke in the generators with a restricted supply of air, or by passing air and steam through a bed of red hot fuel. Producer gas is cheap and used as a fuel mainly in glass furnaces and metallurgical furnaces. It also serves as a fuel in gas engines to operate tractors, motor cars and trucks. It is also used as a source of nitrogen for the preparation of ammonia.

Classification of Heating Gas

- **Low Btu gas:** heating value between 90 and 200-250 Btu per (standard) cubic foot – general agreement
- **Medium Btu gas** – no agreement on definition
- **High Btu gas** above 900 Btu per standard cubic foot – general agreement

http://www.aga.org/Content/NavigationMenu/About_Natural_Gas/Natural_Gas_Glossary/

Standard Cubic Foot The quantity of gas which, at a pressure and temperature of 14.73 psia and 60 F occupies one cubic foot without adjustment for water vapor.

High Btu Gas A term used to designate fuel gases having heating values of pipeline specification, i.e., greater than about 900 Btu per standard cubic foot.

Low Btu Gas Gas with a heating value of less than 250 Btu's per cubic foot. Typically heating values fall between 120 and 180 Btu's per cubic foot.

<http://www.eia.doe.gov/glossary/>

low Btu gas 90-200

<http://www.efcfinance.com/m.html>

low 90-200, medium 200-300,

<http://www.cogeneration.net/EnergyDictionary%20-%20M.htm>

Medium Btu Gas - heating value of between 200 and 300 Btu per cubic foot.

Low Btu Gas - A fuel gas with a heating value between 90 and 200 Btu per cubic foot.

<http://www.renovarenergy.com/howgasused.html>

The heating value of landfill gas (LFG) is 400-550 Btu per cubic foot or about one-half of natural gas, thereby getting the name "medium Btu." High Btu projects process the LFG and remove the carbon dioxide and other impurities until the remaining gas meets natural gas pipeline specifications.

Hydrogen Production

- Possible uses
 - Ammonia manufacture
 - Petroleum refining
 - Fuel for fuel cells
- Produced by initial gasification and water-gas shift reaction
 - $C + H_2O \rightarrow CO + H_2$ ($\Delta H_R = 130$ MJ)
 - $CO + H_2O \rightarrow CO_2 + H_2$ ($\Delta H_R = -41$ MJ)
- Temperature behavior
 - H_2 production favored by low temperatures
 - Need $300\text{ C} < T < 700\text{ C}$ for reaction rate

Reference: National Research Council, *Coal Energy for the Future*, National Academy Press, 1995.

Acidic gases such as H_2S , CO_2 , and HCl are catalyst poisons. They must be removed from the gas stream prior to the water-gas shift reaction to maintain catalyst activity.

The production of hydrogen is an important step in moving to the use of fuel-cells which, in general, require hydrogen as a fuel. We will discuss fuel cells as a separate topic later in the course.

Hydrogen can also be produced by the electrolysis of water, but this is an expensive process and it basically takes electricity which has been generated with whatever efficiency losses are considered for particular processes and converts the electricity back into fuel.

People have talked about the “hydrogen economy” for many years now. In the original discussions of that concept, hydrogen would be produced by electrolysis where the electric power would come from fusion power plants. As we discussed earlier the practical generation of electricity from fusion power is many years off.

Certainly, from the standpoint of global warming, hydrogen is the only fuel that can be burned without producing CO_2 , but conventional methods of hydrogen production can produce CO_2 .

Gasification Reactors

- Entrained flow process – commercial and development
- Fluidized bed process – development and demonstration
- Moving fixed bed process – one commercial, others development
- Notes pages have list of various reactors and their state of development

Reference: National Research Council, *Coal Energy for the Future*, National Academy Press, 1995.

Entrained flow Process

Texaco (US)	Commercial	1,260 – 1,480 C
Shell (Europe/US)	Commercial	1,370 – 1,540 C
Destec (US)	Commercial	1,040 C
Prenflo (Europe)	Commercial/demonstration	1,370 – 1,540 C
Koppers Totzek (Europe)	Commercial	1,480 C
ABB/Combustion Engr	Development	1,040 C
IGC (Japan)	Development	1,260 C
HYCOL (Japan)	Development	1,480 – 1,260 C
VEW (Germany)	Development	

Fluidized-bed Process

KRW(US/Europe)	Demonstration/development	1,010 – 1,040 C
Winkler/Lurgi (Europe)	Demonstration/development	950 C
Tampella/UGas (Finland/US)	Development	980 – 1,040 C
MCT	Demonstration/development	1,090 – 1,260 C

Moving Fixed-bed Process

Lurgi (Europe)	Commercial
British Gas/Lurgi (BG/L)	Demonstration

Gasification Reactors

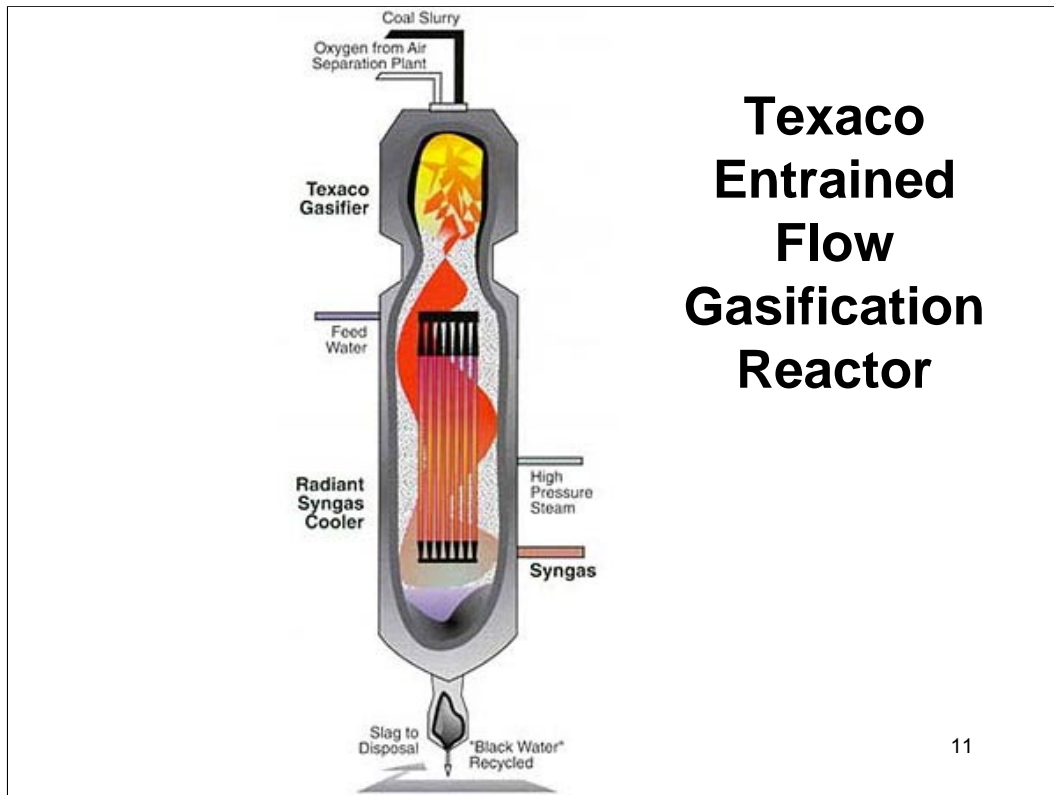
Fixed-bed process (800-1000°C, 10-100 bar)			Fluidized-bed process (800-1100°C, 10-25 bar)		Entrained-flow process (1500-1900°C, 25-40 bar)		
Lurgi DRY	Lurgi Slagger	KILnGAS	KRW	HT-Winider	ShoR Krupp Koppers PRENFLO	Texaco	VEW

Entrained Flow Reactors

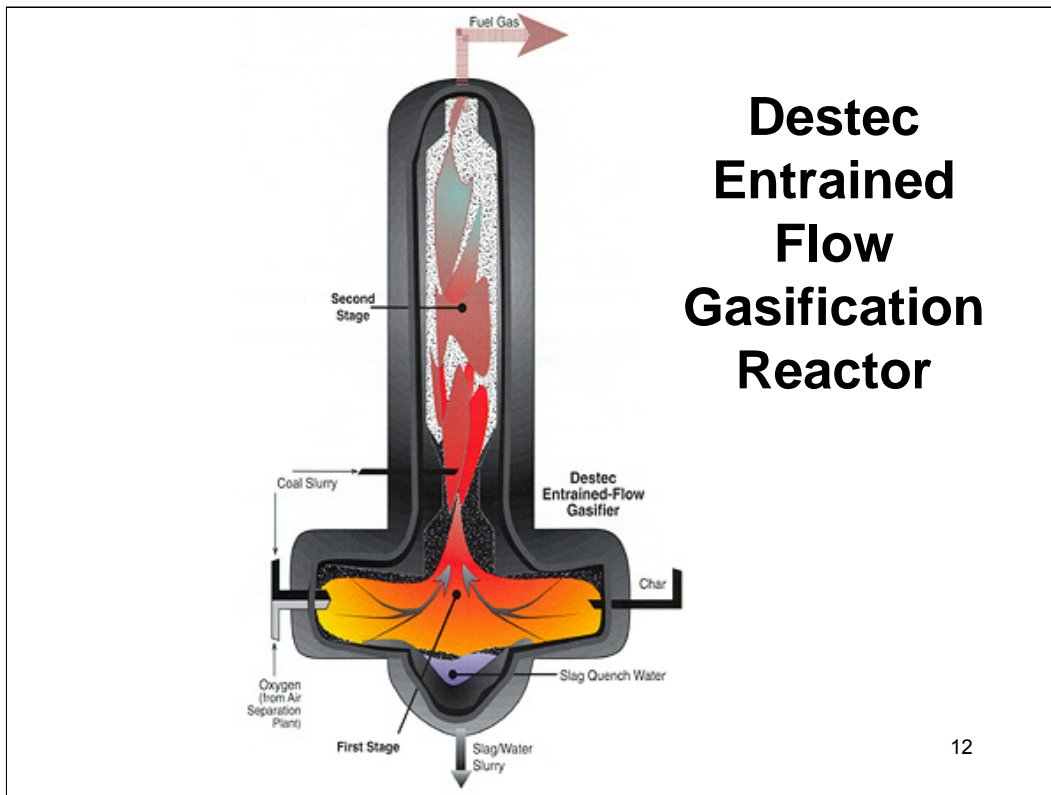
- Powdered coal gasified with a mixture of steam and oxygen (or air)
- Reaction zone is where main part of molten slag is collected
- High temperature products require cooling prior to cleanup
- Little methane, compact, short reaction times, insensitive to coal properties

Reference: National Research Council, *Coal Energy for the Future*, National Academy Press, 1995.

Entrained flow reactors are characterized by high exit temperatures. This leads to short reaction times because of the fast kinetics. The high temperatures make the process work regardless of the properties of the coal, so long as the coal can be pulverized below 200 mesh (44 micrometer) size. The high exit temperatures produce a gasifier that has less efficiency than other types. The gas produced is relatively free of tars, hydrocarbons heavier than methane and nitrogen compounds.



<http://www.netl.doe.gov/coalpower/gasification/pubs/images/Tr6-8-1.jpg>
Texaco entrained flow gasification reactor



Destec entrained flow gasification reactor

<http://www.netl.doe.gov/coalpower/gasification/pubs/images/Tr7-14-1.jpg>

Fluidized-bed Reactors

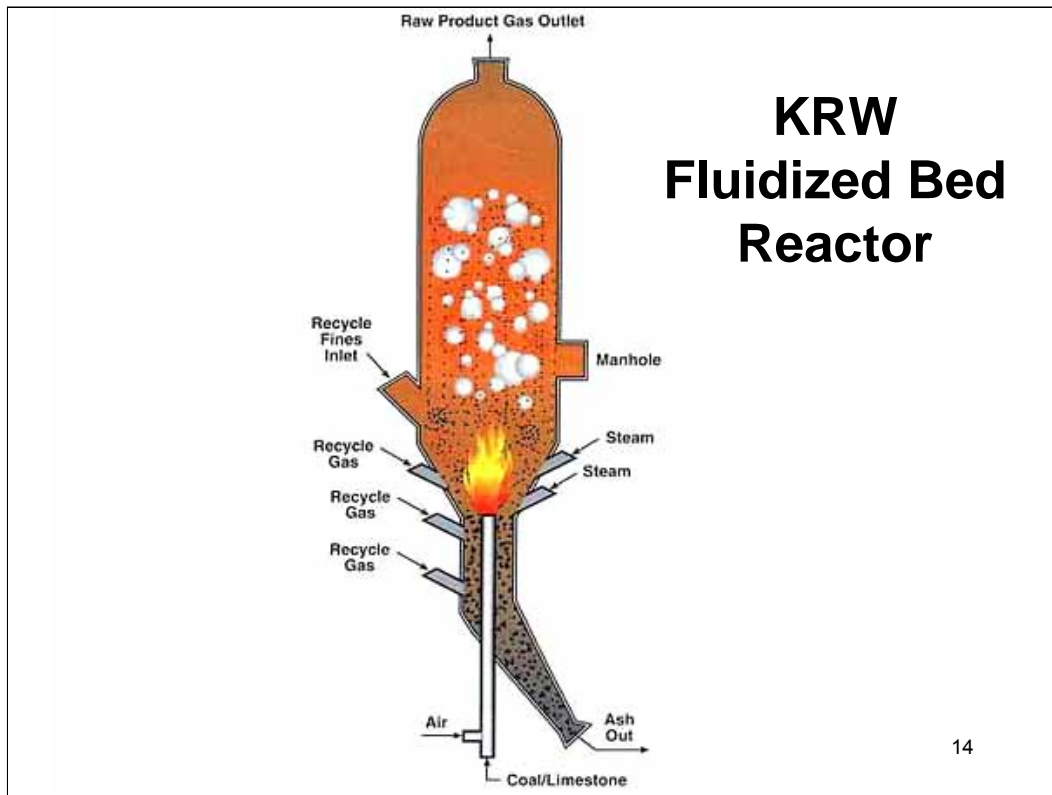
- Operate at 760 C to 1,050 C, depending on coal properties
- Have potential for greater efficiencies due to lower temperatures
- Higher coal throughput rates compared to moving fixed bed
- Less inert ash due to low temperatures may cause more disposal problems

Reference: National Research Council, *Coal Energy for the Future*, National Academy Press, 1995.

The operating temperature depends on the coal reactivity and the ash softening temperature. The greater efficiency is because the outlet temperatures are better suited to gas cleaning processes so that little or no heat removal is required.

No high-pressure systems are commercially available but one atmospheric pressure one is.

The Tampella/U-Gas and the KRW gasifiers have a special ash agglomeration section which can reduce potential problems of the less inert ash.



http://www.netl.doe.gov/coalpower/gasification/pubs/images/29309_101.jpg

KRW Fluidized bed reactor

Moving Fixed-bed Reactors

- Coal moves downward countercurrent to upward flowing gas
- Provides greater efficiency
- More complex and costly than stationary bed systems
- Historically most widely used
 - Over 100 Lurgi units in commercial use

Reference: National Research Council, *Coal Energy for the Future*, National Academy Press, 1995.

The coal fed to this system is approximately 2-inch by one-half-inch. High temperatures above the oxidizing gas inlet decrease as the gases exchange heat and react with the descending coal. Thus the exit temperatures are low.

Some pyrolysis products (methane, light hydrocarbons, tar) escape oxidation and subsequent removal of tar is required.

Fischer-Tropsch Reaction

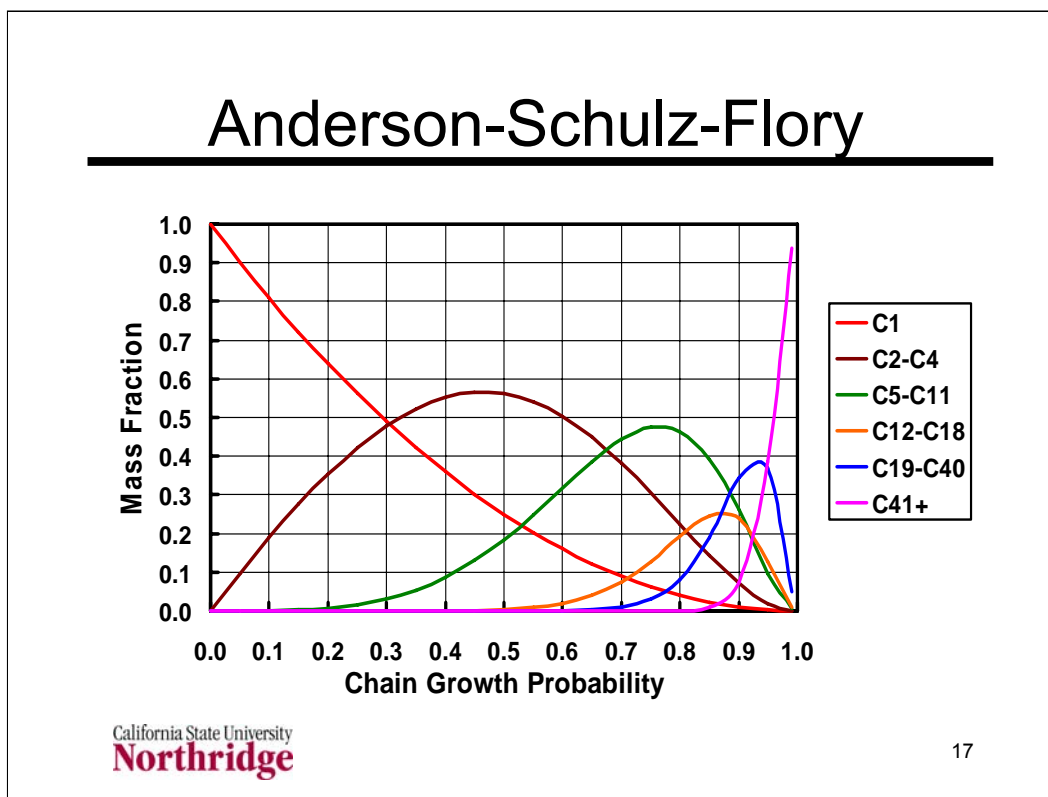
- $n\text{CO} + 2n\text{H}_2 \rightarrow (-\text{CH}_2-)_n + n\text{H}_2\text{O}$
- Uses synthesis gas over catalyst
- Patented in 1925 in Germany
- Basis for modern synthetic liquid fuels
- Interest waned after large discoveries of oil in Middle East during the 1950s
- Current interest in gas to liquid fuels

The Fischer-Tropsch reaction is one path to liquid fuels from coal. It uses a synthesis gas from coal gasification. The synthesis gas can be cleaned to remove sulfur compounds. In fact, this step is generally required to avoid degradation of the catalysts used in the Fischer-Tropsch process.

An alternative to the Fischer-Tropsch process is the direct liquefaction of coal. That will be discussed subsequently.

German gasoline production during World War II and production of synthetic crude oils in South Africa during Apartheid was done by the Fischer-Tropsch process.

The web site, <http://www.fischer-tropsch.org/>, contains a large amount of present and historical information on the Fischer-Tropsch process. The site is sponsored by Syntroleum Corporation in cooperation with Dr. Anthony Stranges, a professor of history at Texas A&M University, whose area of research is the history of alternative fuels processes. This site has several old documents, converted from printed to electronic form by scanners, dating back to the 1920s. It even has records of interviews of German scientists that were obtained after World War II to learn about the progress that they had made on the Fischer-Tropsch process during the War.



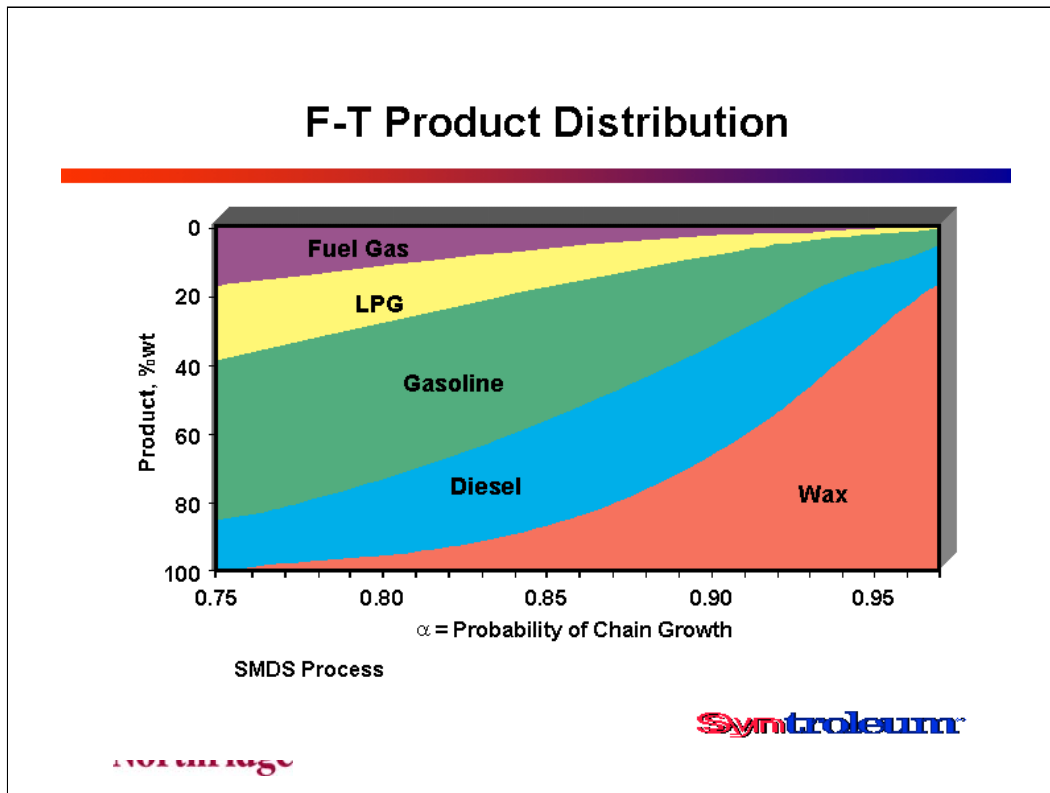
The product yield from Fischer-Tropsch reactions can be characterized by a polymerization distribution equation known as the Anderson-Schulz-Flory distribution. This distribution is given by the following equation, $W_n = n \alpha^{n-1} (1 - \alpha)^2$. In this equation, n is the number of carbon atoms in the resulting molecule, W_n is the mass fraction of a hydrocarbon with n carbon atoms, and α is a factor known as the chain growth probability.

This growth probability factor allows a general picture of the FT process. The design of a process with a particular catalyst and a given set of pressures and temperatures can then be interpreted by its effective chain growth probability.

This parameter is actually determined by measuring the weight fraction distribution and rewriting the distribution equation as follows: $\log(W_n/n) = [\log(\alpha)] n + \log[(1 - \alpha)^2/\alpha]$. This equation says that a plot of $\log(W_n/n)$ versus n should be a straight line with a slope of $[\log(\alpha)]$ and an intercept of $\log[(1 - \alpha)^2/\alpha]$. Thus, measurements of the product distribution, W_n , as a function of n can be plotted in this manner and the value of α can be determined.

The range of C_5 to C_{11} compounds is typical of those found in gasoline and the range from C_{12} to C_{18} is typical of those found in Diesel fuel.

This distribution of actual refinery products is illustrated in the next slide.



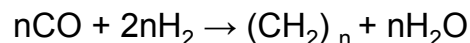
Reference: Paul Schubert, Steve LeViness, Kin Arcuri, and Anthony Stranges, Development of the modern Fischer-Tropsch process (1958-1999), Syntroleum, August 28, 2001. Found at http://63.241.183.24/primary_documents/presentations/acs2001_chicago/chic_slide01.htm

This chart is similar to the previous one, however this one shows the possible combinations of refinery products that are available as a result of the level of Fischer-Tropsch synthesis as measured by the probability of chain growth.

Fischer-Tropsch Reactors

- Significant heat transfer problem due to heat of reaction ~25,000 Btu/lbmole of synthesis gas reacted
- Fixed bed reactors
- Fluidized bed reactors
 - circulating
 - fixed
- Slurry reactors

The Fischer-Tropsch reaction from the last slide is written as follows:

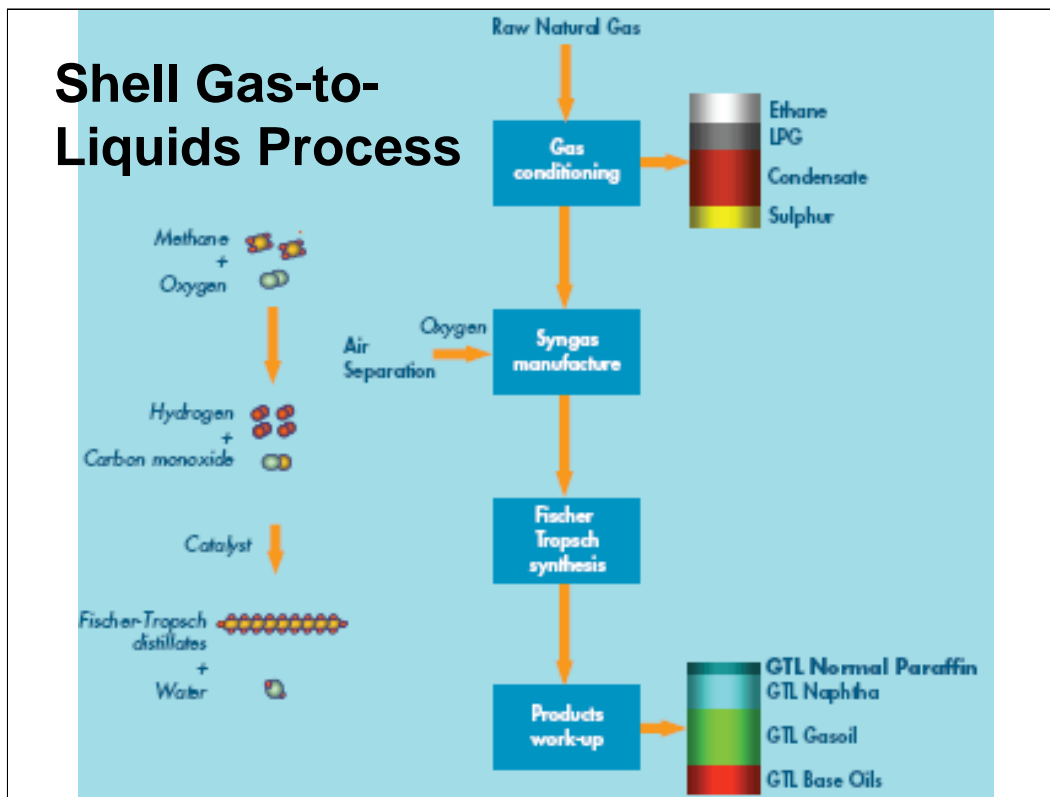


We can use the standard heats of formation for CO, H₂, and H₂O (gas) of -47,518 Btu/lbmole, 0 Btu/lbmole, and -103,696 Btu/lbmole, respectively. The average heat of formation of the liquid fuel product, (CH₂)_n is -8,500n Btu/lbmole. The total moles of synthesis gas reacted in the reaction are 3n (combined total of CO and H₂.)

The heat of reaction is $n(-103,696) - 8,500n - [n(-47,518) + 2n(0)] = -74,948n$ Btu

Dividing this by the 3n moles participating in the reaction gives the approximate energy release of 25,000 Btu/lbmole of synthesis gas shown in the chart. As usual, the negative heat of reaction indicates an energy release.

Additional information on the reactor types is presented on the following charts and note pages.



Reference:

http://www.shell.com/home/Framework?siteId=shellgasandpower-en&FC2=/shellgasandpower-en/html/iwgen/products_and_services/what_is_gtl/gas_to_liquid/zzz_lhn.html&FC3=/shellgasandpower-en/html/iwgen/products_and_services/what_is_gtl/gas_to_liquid/whatisgtl_0112_1532.html

Yes that is really the URL!

Gas-to-liquid (GTL) conversions are used when there is no ready market for gas due to a lack of pipelines. In this case the gas is usually flared (burned) or reinjected for later use.

Gas can be transported if it is converted to a liquid. There are two ways to do this. One is to produce liquified natural gas which can be transported to a pipeline location and vaporized there. Several LNG plants have been proposed for the West Coast of the US, but many of these are controversial and may not be built.

Shell has an operating plant in Malaysia now producing liquid fuels from natural gas using the schematic shown above. They are also constructing a plant in Qatar, in conjunction with Qatar Petroleum that is scheduled for completion in two phases with projected dates of 2010 and 2011. When completed the plant will produce 140,000 barrels per day (bpd) of gas-to-liquid (GTL) products as well as approximately 120,000 bpd of associated condensate and liquefied petroleum gas

Energy Policy Acts – Coal

- 1992 EAct – Title XII
 - R&D and commercial application programs
 - Clean coal waste-to-energy
 - Coal in diesel engines
 - Clean Coal Technology (CCT) program
 - Underground coal gasification
 - and many more
- 2005 EAct Title IV

The 1992 and 2005 Energy Policy Act had separate titles dedicated to coal. The main focus of that title was the development of R&D programs that could lead to environmentally acceptable uses of coal.

The provisions in the 2005 act are outlined below

Subtitle A—Clean Coal Power Initiative

Sec. 401. Authorization of appropriations.

Sec. 402. Project criteria.

Sec. 403. Report.

Sec. 404. Clean coal centers of excellence.

Subtitle B—Clean Power Projects

Sec. 411. Integrated coal/renewable energy system.

Sec. 412. Loan to place Alaska clean coal technology facility in service.

Sec. 413. Western integrated coal gasification demonstration project.

Sec. 414. Coal gasification.

Sec. 415. Petroleum coke gasification.

Sec. 416. Electron scrubbing demonstration.

Sec. 417. Department of Energy transportation fuels from Illinois basin coal.

DOE's Coal Roadmap

- Advanced technologies that would allow efficient energy use with a goal of near zero emissions, including greenhouse gases
- Use integrated facilities that would produce both energy and chemicals
- Develop modular facilities that could meet local energy and chemical needs

Reference: <http://www.netl.doe.gov/technologies/coalpower/cctc/pubs/CCT-Roadmap.pdf> (Accessed April 4, 2008)

Developed in conjunction with Electric Power Research Institute and Coal Utilization Research Council

Based on forecasts that coal will continue to constitute the main fuel source for electric power. Seeks ways in which current technology can evolve by appropriate demonstration and research projects into near-zero emission plants with increased efficiency and reduced cost.

Carbon capture and sequestration is considered with the goal of 90% capture with no more than a 10% increase in the delivered cost of electricity. Technology is aimed at both new plants and existing facilities.

Will build on previous research, including low-polluting combustion, gasification, high efficiency furnaces and heat exchangers, advanced gas turbines, fuel cells, and fuels synthesis, and adds other critical technologies and system integration techniques, coupled with CO₂ capture and recycling or sequestration.

Planning horizon is 2020 with examination of effects out to 2050.

Roadmap Performance Targets <i>(Represents best integrated plant technology capability)</i>			
	Reference Plant*	2010	2020
Air Emissions	98% SO ₂ removal	99%	>99%
	0.15 lb/10 ⁶ Btu NO _x	0.05 lb/10 ⁶ Btu ⁽¹⁾	<0.01 lb/10 ⁶ Btu
	0.01 lb/10 ⁶ Btu Particulate Matter	0.005 lb/10 ⁶ Btu ⁽²⁾	0.002 lb/10 ⁶ Btu
	Mercury (Hg) ⁽³⁾	90% removal ⁽⁴⁾	95% removal
By-Product Utilization	30% ⁽⁵⁾	50% ⁽⁶⁾	near 100% ⁽⁶⁾

*Reference plant has performance typical of today's technology;
Improved performance achievable with cost/efficiency tradeoffs.

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Reference:

<http://www.netl.doe.gov/technologies/coalpower/cctc/ccpi/pubs/CCT-Roadmap.pdf> (Accessed April 4, 2008)

The roadmap document is a combined product of the DOE, the Electric Power Research Institute, and the Coal Utilization Research Council

(1) For existing plants, reduce cost for achieving <0.10 lb/10⁶ Btu using combustion control by 25% compared to SCR by 2010; same cost reduction for 0.15 lb/10⁶ Btu by 2005

(2) Achieve PM targets for existing plants in 2010: 99.99% capture of 0.1-10 micron particles

(3) Some Hg reduction is being achieved as a co-benefit with existing environmental control technologies

(4) 2005 objective to achieve 50-70% Hg removal to less than 75% of the cost of activated carbon injection

(5) Represents average for existing plant locations

(6) Target represents technically achievable for new or existing plants; economics are site specific

Roadmap Performance Targets⁽¹⁾

(Represents best integrated new plant technology capability)

	Reference Plant	2010	2020
Plant Efficiency (HHV)⁽²⁾	40%	45-50%	50-60%
Availability⁽³⁾	>80%	>85%	≥90%
Plant Capital Cost⁽²⁾ \$/kW	1000 – 1300	900 – 1000	800 – 900
Cost of Electricity⁽⁴⁾ ¢/kWh	3.5	3.0-3.2	<3.0

- (1) Targets are w/o carbon capture and sequestration and reflect current cooling tower technology for water use
- (2) Range reflects performance projected for different plant technologies that will achieve environmental performance and energy cost targets
- (3) Percent of time capable of generating power (ref. North American Electric Reliability Council)
- (4) Bus-bar cost-of-electricity in today's dollars; Reference plant based on \$1000/kW capital cost, \$1.20/10⁶ Btu coal cost

Reference: <http://www.netl.doe.gov/technologies/coalpower/cctc/pubs/CCT-Roadmap.pdf> (Accessed April 4, 2008)

Performance Targets: Coal-to-Fuel		
	2010	2020 Vision 21
Plant Efficiency¹	45 - 65%	60 - 75%
Plant Capital Cost²	\$35,000/bpd	<\$25,000/bpd liq. \$3-7/scfd H₂
Product Cost - Liquids - Hydrogen³	\$30/bbl --	<\$30/bbl \$3-5/10⁶ Btu
(1) Efficiency depends on ratio of H ₂ to electricity (2) Capital cost of H ₂ plant depends on ratio of H ₂ to electricity (3) H ₂ cost depends on ratio of H ₂ to electricity		

Reference: <http://www.netl.doe.gov/technologies/coalpower/cctc/pubs/CCT-Roadmap.pdf>

Fuel flexibility enables the use of low-cost indigenous fuels, renewables, and waste materials. For advanced, high-performance gas turbines, and hybrids incorporating advanced turbines/fuel cells, fuel flexibility requires research to address combustion of low-Btu gases and maintaining low-NO_x emissions at higher temperatures. Product flexibility allows power suppliers to supplement revenues by designing plants to site- or region-specific markets for high-value by-products. Many chemical and fuel processes, however, require nearly contaminant-free syngas.

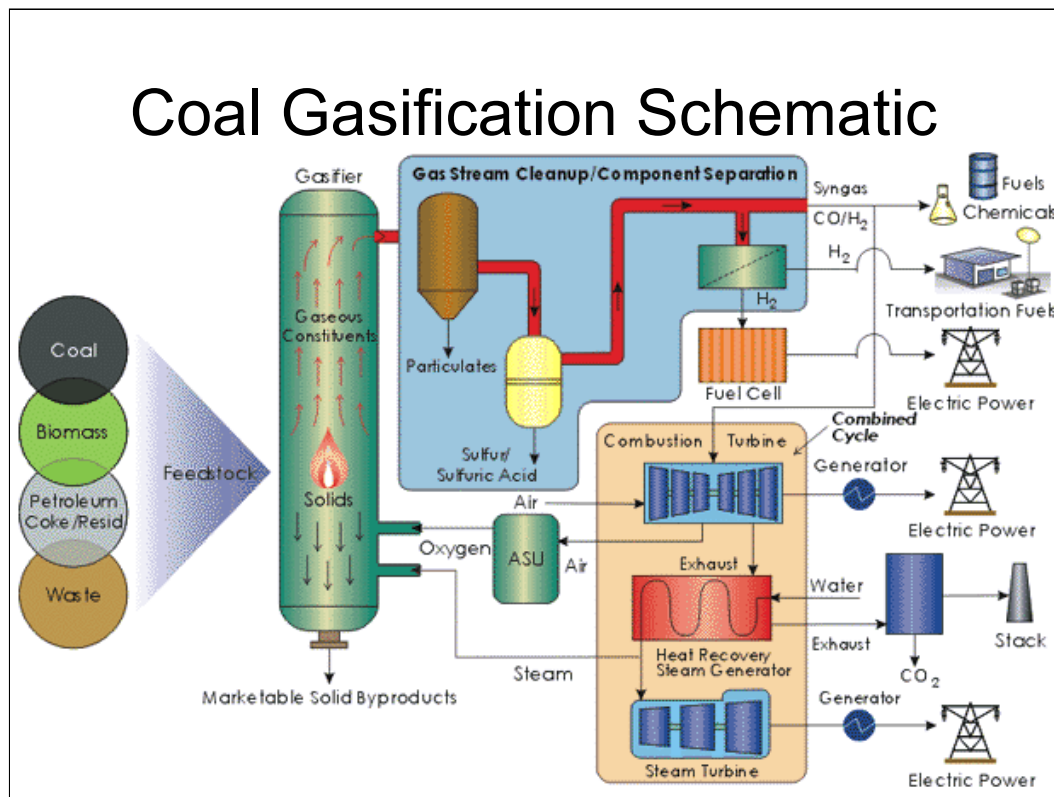
Power system developments are moving toward higher efficiency to lower CO₂ emissions on a per-Btu basis and toward more concentrated CO₂ emission streams through oxygen-rather than air-based gasification and combustion. Air separation efforts support the move to oxygen-based systems. Ultimately, CO₂ must be captured either through chemical or physical separation methods.

Integrated Coal Gasification

- Integrated, combined-cycle, coal gasification (IGCC) integrates
 - coal gasification to produce syngas
 - syngas cleaning to reduce emissions
 - CO₂ removal from syngas to storage
 - solids conversion to useful byproducts
 - syngas used as gas turbine fuel
 - waste heat from gas turbine used to drive steam turbine

The basic idea of IGCC is to integrate a system of coal gasification with immediate use of the gas to produce electricity. In this process, the solid materials that produce bottom ash and fly ash in the combustion process are removed during the gasification process and the resulting gaseous fuel is reacted to remove the sulfur prior to its use in the combustion turbines.

The combined cycle process is similar to that used for ordinary gas turbines fueled with natural gas. Here, the fuel is the syngas which produces power in the turbines. As typical, the waste heat from the turbine is available to generate steam that can be used in a simple steam cycle to produce additional electric power.



http://www.fe.doe.gov/coal_power/gasification/gasification_schematic.shtml (Accessed November 2002)

This chart shows a typical schematic diagram of the IGCC process.

According to the DOE web site: "Gas from coal is not only a clean fuel but also a rich source of chemicals. One of the primary products of coal gasification is hydrogen, the cleanest of all fuels. Coal-derived gas can also be recombined into liquid fuels, including high-grade transportation fuels, and a variety of petrochemicals. In contrast to conventional combustion, carbon dioxide exits a coal gasifier in a concentrated stream rather than diluted in a high volume of flue gas. This allows the carbon dioxide to be captured more easily and used for commercial purposes or sequestered."

Because this diagram shows a generic IGCC process, not all the systems shown here may be present in an actual process. Furthermore, the exact byproducts will vary from process to process. In particular, the use of membrane separation to produce hydrogen, implied in the diagram above, has not been part of any demonstration products. However, the overall idea of the ICCG process is an alternative to coal combustion followed by extensive pollution control devices including selective catalytic reduction for NO_x removal, scrubbers for SO₂ removal, and particulate filters to remove particulate matter.

Note that the steam required for the steam-reforming process in the gasifier is produced by sending make up water through the same steam generator that is used to produce steam for the steam turbine.

The key comparison between these two alternatives is the ultimate cost of electricity between the two processes.

Wabash Demonstration

- Project timeline
 - selected in 1991
 - operated from November 1995 to December 1999
 - final report in September 2000
- Repowered a 1950s coal-fired plant
 - Old: 33% efficient 90-MW(e)
 - New: 40% efficient, 262-MWe (net) – heat rate of 8,910 Btu/kWh (HHV)

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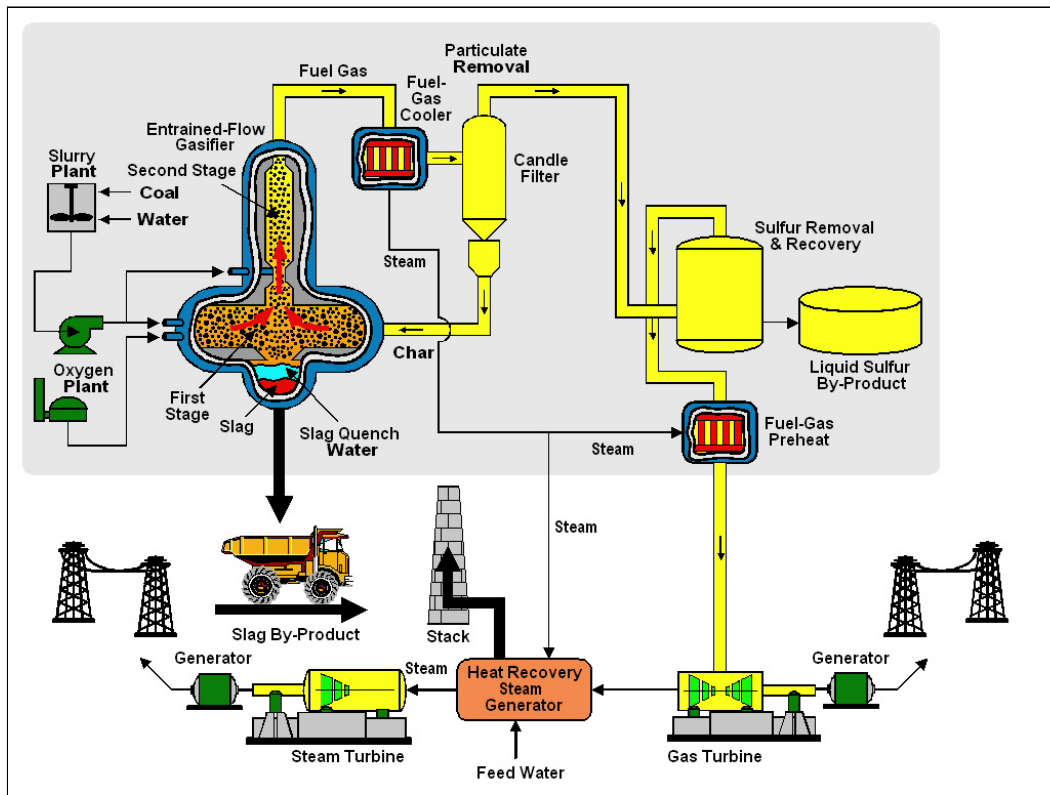
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Reference:

<http://www.lanl.gov/projects/cctc/factsheets/wabsh/wabashrdemo.html>
(Accessed September 2002)

Environmental: The SO₂ capture efficiency was greater than 99%, keeping SO₂ emissions consistently below 0.1 lb/10⁶ Btu and reaching as low as 0.03 lb/10⁶ Btu; and SO₂ was transformed into 99.99% pure sulfur. The NO_x emissions were controlled by steam injection down to 0.15 lb/10⁶ Btu. Coal ash was converted to a low-carbon vitreous slag, impervious to leaching and valued as an aggregate in construction or as grit for abrasives and roofing materials; and trace metals from petroleum coke were also encased in an inert vitreous slag.

Operations: Ash deposition at the fire tube boiler inlet, which was corrected by a change to the flow path geometry; Particulate breakthrough in the hot gas filter, which was largely solved by changing to improved metallic candle filters. Chloride and metals poisoning of the COS catalyst, which was eliminated by installation of a wet chloride scrubber and a COS catalyst less prone to poisoning. Cracking in the gas turbine combustion liners and tube leaks in the heat recovery steam generator (HRSG). Resolution involved replacement of the gas turbine fuel nozzles and liners and modifications to the HRSG to allow for more tube expansion. Gas turbine damage to rows 14 through 17 of the compressor causing a 3- month outage. Availability of the gasification plant steadily improved reaching 79.1% in 1999. (continued notes page after next)



Reference: <http://www.lanl.gov/projects/cctc/factsheets/wabsh/wabashrdemo.html>

The Destec process features an oxygen-blown, continuous-slugging, two-stage entrained flow gasifier. Coal is slurried, combined with 95% pure oxygen, and injected into the first stage of the gasifier, which operates at 2600 °F/400 psig. In the first stage, the coal slurry undergoes a partial oxidation reaction at temperatures high enough to bring the coal's ash above its melting point. The fluid ash falls through a tap hole at the bottom of the first stage into a water quench, forming an inert vitreous slag. The syngas flows to the second stage, where additional coal slurry is injected. This coal is pyrolyzed in an endothermic reaction with the hot syngas to enhance syngas heating value and improve efficiency.

The syngas then flows to the syngas cooler, essentially a firetube steam generator, to produce high-pressure saturated steam. After cooling in the syngas cooler, particulates are removed in a hot/dry filter and recycled to the gasifier. The syngas is further cooled in a series of heat exchangers. The syngas is water scrubbed to remove chlorides and passed through a catalyst that hydrolyzes carbonyl sulfide into hydrogen sulfide. Hydrogen sulfide is removed in the acid gas columns. A Claus unit is used to produce elemental sulfur as a salable by-product. The "sweet" gas is then moisturized, preheated, and piped to the power block. The power block consists of a single 192-MWe GE MS7001FA (Frame 7FA) gas turbine, a Foster Wheeler single-drum heat-recovery steam generator with reheat, and a 1952 vintage Westinghouse reheat steam turbine.

Wabash Fuel Analysis

	Coal	Coke
Moisture, % by wt.	15.2	7
Ash, % by wt.	12	0.3
Volatile, % by wt.	32.8	12.4
Fixed Carbon, % by wt.	39.9	80.4
Sulfur, % by wt.	1.9	5.2
Heating Value, Btu/lb	10,536	14,282

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(continued from notes page before last)

Economics: Overall cost of the gasification and power generation facilities was \$417 million, including engineering and environmental studies, equipment procurement, construction, pre-operations management, and startup. Preliminary estimates for a future dual-train facility are \$1,200/kW. Costs could fall to under \$1,000/kW for a greenfield plant with advances in turbine technology.

Summary: The Wabash River Coal Gasification Repowering Project repowered a 1950s vintage pulverized coal-fired plant, transforming the plant from a nominally 33% efficient, 90-MWe unit into a nominally 40% efficient, 262-MWe (net) unit. Cinergy, PSI's parent company, dispatches power from the project, with a demonstrated heat rate of 8,910 Btu/kWh (HHV), second only to their hydroelectric facilities on the basis of environmental emissions and efficiency.

Other factors: Beyond the integration of an advanced gasification system, a number of other advanced features contributed to the high energy efficiency. These included: (1) hot/dry particulate removal to enable gas cleanup without heat loss, (2) integration of the gasifier high-temperature heat recovery steam generator with the gas turbine-connected HRSG to ensure optimum steam conditions for the steam turbine, (3) use of a carbonyl sulfide (COS) hydrolysis process to enable high-percentage sulfur removal, (4) recycle of slag fines for additional carbon recovery, (5) use of 95% pure oxygen to lower power requirements for the oxygen plant, and (6) fuel gas moisturization to reduce steam injection requirements for NO_x control.

Syngas Composition

	Coal	Coke
Nitrogen, % by vol.	1.9	1.9
Argon, % by vol.	0.6	0.6
Carbon Dioxide, % by vol.	15.8	15.4
Carbon Monoxide, % by vol.	45.3	48.6
Hydrogen, % by vol.	34.4	33.2
Methane, % by vol.	1.9	0.5
Total Sulfur,ppmv	68	69
Higher Heating Value, Btu/scf	277	268

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Reference: <http://www.osti.gov/bridge/servlets/purl/787567-a64JvB/native/787567.PDF>

Over the four-year demonstration period starting in November 1995, the facility operated approximately 15,000 hours and processed approximately 1.5 million tons of coal to produce about 23×10^{12} Btu of syngas. For several of the months, syngas production exceeded one trillion Btu. By the beginning of the final year of operation under the demonstration, the 262-MWe IGCC unit had captured over 100 million pounds equivalent of SO_2 .

Operational Performance: The first year of operation was plagued by problems primarily with: (1) ash deposition at the inlet to the fire tube boiler, (2) particulate breakthrough in the hot gas filter system, and (3) chloride and metals poisoning of the COS catalyst. A modification to the hot gas path flow geometry corrected the ash deposition problem. Replacement of the ceramic candle filters with metallic candles proved to be largely successful. A follow-on metallic candle filter development effort ensued using a hot gas slipstream, which resulted in improved candle filter metallurgy, blinding rates, and cleaning techniques. The combined effort all but eliminated downtime associated with the filter system by the close of 1998. Installation of a wet chloride scrubber eliminated the chloride problem by September 1996 and use of an alternate COS catalyst less prone to trace metal poisoning provided the final cure for the COS system by October 1997.

The second year of operation identified cracking problems with the gas turbine combustion liners and tube leaks in the HRSG. Replacement of the fuel nozzles and liners solved the cracking problem. Resolution of the HRSG problem required modification to the tube support and HRSG roof/penthouse floor to allow for more expansion.

By the third year, downtime was reduced to nuisance items such as instrumentation-induced trips in the oxygen plant and high-maintenance items such as replacement of high-pressure slurry burners every 40–50 days.

Continued on next notes page

Design vs. Performance

	Design	Actual
Syngas capacity (MMBtu/hr)	1,780	1,690
Combustion turbine MW	192	192
Steam turbine capacity, MW	105	96
Net power, MW	262	252
Heat rate (MMBTU/hr)	9,080	8,900
SO ₂ Emissions (lb/MMBtu)	<0.2	<0.1
Syngas heat content (Btu/lb _m)	280	275+
Syngas sulfur content (ppmv)	<100	<100

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(continued from notes previous notes page)

In the third year, the IGCC unit underwent fuel flexibility tests. The unit operated effectively, without modification or incident, on a second coal feedstock, a blend of two different Illinois #6 coals, and petroleum coke (petcoke). These tests added to the fuel flexibility portfolio of the gasifier, which had previously processed both lignite and subbituminous coals during its earlier development. The overall thermal performance of the IGCC unit actually improved during petcoke operation. The unit processed over 18,000 tons of high-sulfur petcoke and produced 350,000 x 10⁶ Btu of syngas. There was a negligible amount of tar production and no problems were encountered in removing the dry char particulate despite a higher dust loading.

Steam injection controls NO_x emissions down to 0.15 lb/ 10⁶ Btu. This is the emission limit being sought under the EPA SIP call related to ozone nonattainment areas. Also, particulate emissions are below detection limits.

The ash component of the coal results in a low-carbon vitreous slag, impervious to leaching and valued as an aggregate in construction or as grit for abrasives and roofing materials. Also, the trace metal constituents in the petcoke were effectively captured in the slag produced.

Economics: The overall combined cost of the gasification and power generation facilities was \$417 million at completion. This cost includes engineering and environmental studies, equipment procurement, construction, pre-operations management (including operator training), and startup. Escalation during the project is included. Startup includes the costs of construction and operations, excluding coal and power, up to the date of commercial operation in December 1995. Soft costs such as legal and financing fees and interest during construction are not included. Project participants project future costs of \$1,200/kW for dual-train repowered facilities, and greenfield costs under \$1,000/kW, with advances in turbine technology.

Tampa IGCC Project

- Power production 313 MW(e) gross, 250 MW(e) net
- Efficiency and heat rate
 - 38.4% (LHV)
 - 9,350 Btu/kWh (HHV)
- SO₂ emissions 0.15x10⁻⁶ lb_m/Btu
- NO_x emissions 0.27x10⁻⁶ lb_m/Btu
- Final report in 2002; still in operation

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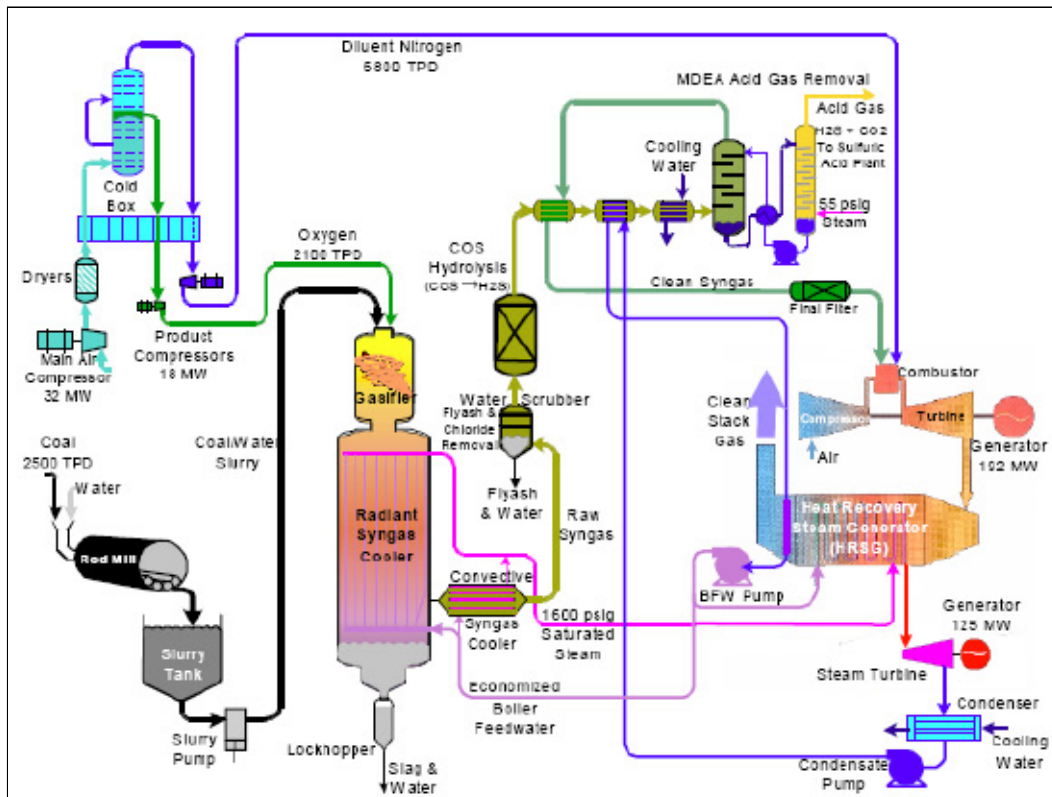
Reference: <http://www.tampaelectric.com/data/files/PolkDOEFinalTechnicalReport.pdfm>
accessed April 5, 2008

Tampa Electric Company Polk Power Station, Unit No. 1 Mulberry, Polk County, FL
Plant Capacity/Production 313 MWe (gross), 250 MWe (net); **Coal** Illinois #6, Pittsburgh #8, Kentucky #11, and Kentucky #9; 2.5%-3.5% sulfur

Technology Advanced integrated gasification combined-cycle (IGCC) system using Texaco's pressurized, oxygen-blown, entrained-flow gasifier technology.

Participants: Texaco, General Electric, Air Products and Chemicals, Monsanto, TECO Power Services, Bechtel. Total cost \$303 million (49%DOE)

Several modifications to the original design and procedures were required to achieve the recent high availability, including: (1) removing or modifying some of the heat exchangers in the high-temperature heat recovery system and making compensating adjustments in the balance of the system to resolve the ash plugging problems, (2) additional solid particle erosion protection for the combustion turbine to protect the machine from ash, (3) implementing hot restart procedures to reduce gasifier restart time by 18 hours, (4) adding a duplicate fines handling system to deal with increases fines loading resulting from lower than expected carbon conversion, (5) revising operating procedures to deal with high shell temperatures in the dome of the radiant syngas cooler, and (6) making various piping changes to correct for erosion and corrosion in the process and coal/water slurry systems. A COS hydrolysis unit was installed in 1999 to further reduce SO₂ emissions, enabling the station to meet recent more stringent emissions restrictions. This unit converts COS produces in the gasifier to H₂S which is more easily removed in the sulfur clean-up process.



<http://www.tampaelectric.com/data/files/PolkDOEFinalTechnicalReport.pdf>
(Accessed April 4, 2008)

This plant uses a Texaco gasifier in which a coal/water slurry and oxygen are reacted at high temperature and pressure. The syngas product leaves the top of the gasifier and molten ash flows from the bottom of the gasifier into a water filled sump. There the ash becomes a solid.

After leaving the gasifier, the syngas flows into a high-temperature heat-recovery unit (HTHRU). The heat exchange in this unit, between syngas and high-pressure water, cools the syngas and produces-pressure steam. After the HTHRU the syngas enters a series of steps where particulates and sulfur species are removed. SO_2 emissions are less than $0.15 \text{ lb}/10^6 \text{ Btu}$ (97% capture). After this clean-up, the syngas is then sent to the combustion turbine to be used for power production.

A GE MS 7001FA combustion turbine generates 192 MWe (gross). Thermal NO_x is controlled to below $0.27 \text{ lb}/10^6 \text{ Btu}$ by injecting nitrogen. A steam turbine uses steam produced by cooling the syngas and superheated with the combustion turbine exhaust gases in the heat recovery steam generator (HRSG) to produce an additional 124 MWe. The plant heat rate is 9350 Btu/kWh (HHV), which is an efficiency of 38.4% (LHV).

Kentucky Pioneer IGCC

- Demonstration project scheduled to start operation in 2004
 - To start with coal and add RDF later
 - Capacity (540, 400) MW(e) (gross, net)
- Similar to previous projects with addition of molten carbonate fuel cell (2 MWe)
- Project cancelled August 2005
- Fuel cell project moved to Wabash River, but never received fuel

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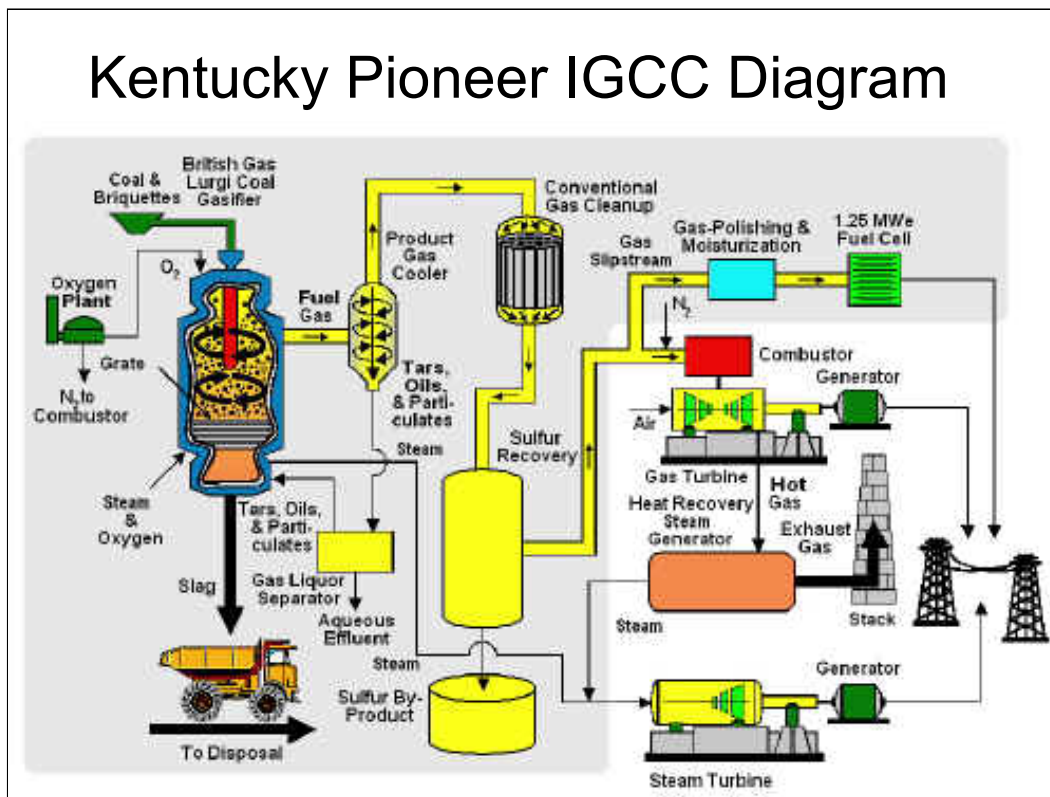
Reference: <http://www.lanl.gov/projects/cctc/factsheets/clnen/cleanedemo.html> (accessed November 2002) The IGCC system proposed here was intended for use in both new plants and repowering of old plants. The planned heat rate of the demonstration facility was estimated at 8,560 Btu/kWh (40% efficiency) with a final target heat rate of 8,035 Btu/kWh (42.5% efficiency) for future commercial applications.

The molten carbonate fuel cell was to be fueled by gas produced in the gasifier; the fuel cell was expected to have a heat rate of 7,379 Btu/kWh (46.2% efficiency). Because of problems in the development of the demonstration plant, the fuel cell demonstration was moved to the Wabash river plant. Although the fuel cell was installed there it was never operated because it could not acquire natural gas fuel for comparison.

The final report on the fuel cell project (a great example of how to write a report about a failed project that says almost nothing about the project) is available at the web site: <http://www.netl.doe.gov/technologies/coalpower/cctc/ccpi/pubs/Fuel%20Cell%20Final%20Report042706.pdf> (accessed April 5, 2008)

Additional details on the plans for the project are shown on the next notes page. Here is the official DOE description of the end of the project

In November 1999, DOE signed the cooperative agreement that launched this project. The National Environmental Policy Act (NEPA) requirements for the IGCC portion of the project were met with an Environmental Impact Statement (EIS) and issuance of a Record of Decision on January 29, 2003. The NEPA process for the MCFC portion of the project was satisfied with a Categorical Exclusion (CX) on the same date. Installation of the MCFC and associated support equipment at the Wabash River Generating Station was completed in August 2004, but operation was put on hold pending closure on a natural gas purchase agreement needed to support MCFC comparative testing on natural gas and synthesis gas. In October 2004, the Kentucky Public Service Commission (PSC) withdrew its approval of an agreement by East Kentucky Power Cooperative, Inc. to purchase electric power from the proposed Kentucky Pioneer Energy generating plant. Due to issues with proceeding at the proposed project site, and lack of progress in moving forward, DOE provided notice to the participant in August 2005 that project closeout activities had been initiated. A Final Report on the Fuel Cell Demonstration was issued in February 2006.



http://www.lanl.gov/projects/ccto/factsheets/clnen/images/clnen_schematic.jpg. (Accessed November 2002)

Technology/Project Description The gasifier is supplied with steam, oxygen, limestone flux, and a coal and municipal waste blend. Raw fuel gas exiting the gasifier is washed and cooled. Hydrogen sulfide and other sulfur compounds are removed. Elemental sulfur is reclaimed and sold as a by-product. Tars, oils, and dust are recycled to the gasifier. The resulting clean, medium-Btu fuel gas fires a gas turbine. A small portion of the clean gas is used for the molten carbonate fuel cell (MCFC).

The MCFC uses a molten carbonate electrolyte placed between the porous anode and cathode. Fuel (desulfurized, heated medium-Btu fuel gas) and steam are fed continuously into the anode; CO_2 -enriched air is fed directly into the cathode. Chemical reactions in the MCFC reform the fuel gas to hydrogen which then produces DC power. The DC power is then converted to AC power in an inverter for transmission to the grid.

Operation was planned to start with 100% coal with slowly increasing levels of RDF throughout the demonstration. This method will allow the development of a database of plant performance at various levels of RDF feed.

Coal: High-sulfur Kentucky bituminous coal blended with municipal solid waste

Technology: Integrated gasification combined-cycle (IGCC) using a BGL (formerly British Gas/Lurgi) slagging fixed-bed gasification system coupled with Fuel Cell Energy's molten carbonate fuel cell (MCFC)

Project Funding

Total cost	\$431,932,714	100%
DOE	\$78,086,357	18%
Participant	\$353,846,225	82%

Estimated electricity costs

- Total cost of \$431,932,714 for 400 MW is a capital cost of \$1,079.83/kW
- Assumptions
 - Thirty year lifetime, 12% ROI (CRF = 0.12414)
 - Annual O&M costs are 5% of capital cost
 - Annual taxes/insurance 10% of capital cost
 - Capacity factor is 85%
- Electricity cost is \$0.0498/kWh

No estimates of electricity costs were readily available for this unit. An estimate was prepared by making the following assumptions:

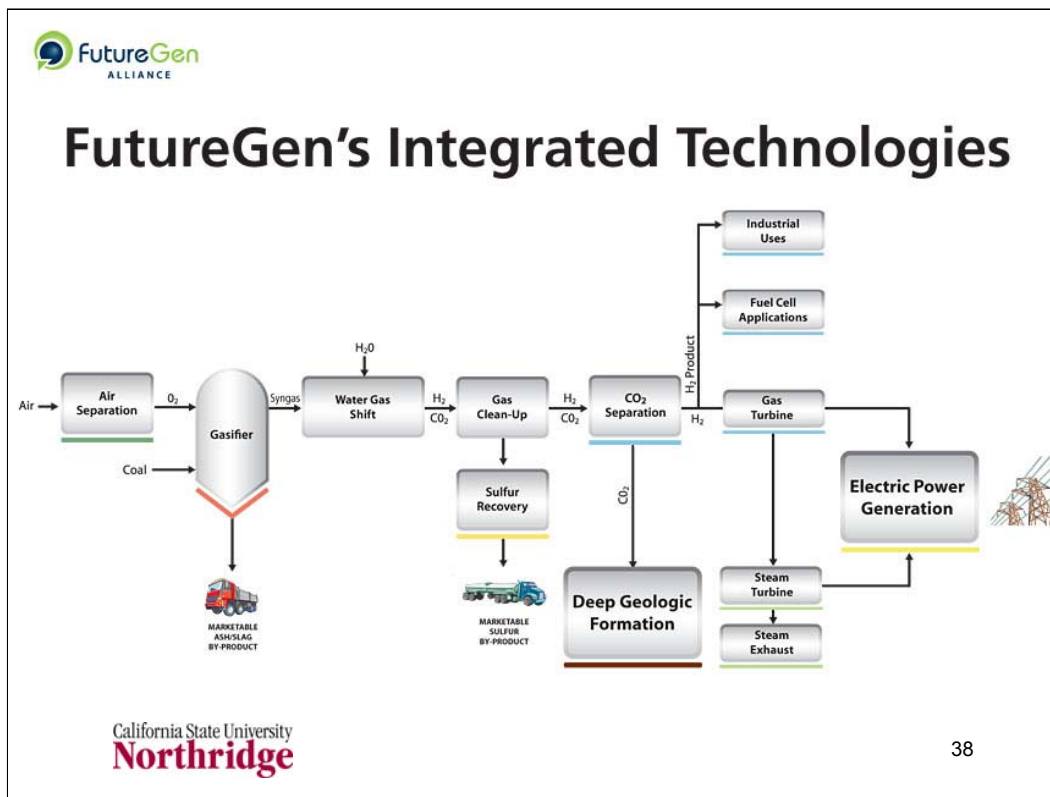
30 year lifetime and 12% annual return on capital; these two assumptions gave a capital recovery factor of 0.12414

With the annual cost of \$1,079.83/kW, this capital recovery factor makes the annual cost of capital \$134.05/kW.

Assume that the annual operating and maintenance (O&M) are 5% of the capital costs and the annual taxes and insurance are 10% of total capital cost

Assume a capacity factor of 85% giving 2,978,400,000 kWh/yr of energy.

Initial capital cost	\$431,932,714
Power capacity (kW)	400,000
Capital recovery factor	0.12414
Annual capital cost	\$53,621,707
Annual taxes and insurance	\$43,193,271
Annual O&M cost	\$21,596,636
Plant heat rate (Btu/kWh)	8,035
Fuel cost (\$/Btu)	1.25E-06
Annual fuel cost	\$29,914,305
Total annual costs	\$148,333,954
Capacity factor	85%
Total annual kWh	2,978,400,000
Dollars per kWh	\$0.0498



Reference (accessed April 4, 2005): <http://www.futuregenalliance.org/>

FutureGen is a proposed partnership between the US Department of Energy (DOE) and industrial participants. Some of the industrial participants include: American Electric Power, Anglo American, BHP Billiton, the China Huaneng Group, CONSOL Energy Inc., E.ON U.S., Foundation Coal, Luminant, PPL Corporation, Rio Tinto Energy America, Peabody Energy, Southern Company, and Xstrata Coal.

The main feature of this plant was the production of the syngas consisting only of CO_2 and hydrogen. The CO_2 would be then captured and sequestered. The hydrogen would be used to fuel the combustion turbine. In addition, it could be used in a fuel cell or an industrial process requiring hydrogen.

The proposed plant shown in the schematic was cancelled by DOE in January 2008 because of increasing costs.

FutureGen Alliance

- Twelve companies plus Department of Energy in \$1.5 (\$1.8) billion project
 - DOE to provide 74% of funding
 - Build a coal-fired power plant with “near-zero emissions” and carbon sequestration
 - Recently changed to remove hydrogen production from plan
 - Project site in Mattoon, IL selected 12/07
 - DOE changes plans in 1/08

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References (accessed April 4, 2005): <http://www.futuregenalliance.org/>
<http://www.iht.com/articles/ap/2007/12/19/america/Coal-Plant-Optional.php>
<http://www.netl.doe.gov/technologies/coalpower/futuregen/index.html>

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The proposed plant shown in the schematic was cancelled by DOE in January 2008 because of increasing costs. DOE is planning to focus its clean coal research funding on implementing demonstration projects on carbon capture and sequestration. This is to be done at IGCC demonstration projects. Much of the cost overrun on the proposed FutureGen plant was associated with the hydrogen production.

The FutureGen alliance is seeking to get continuing funding for their original project from the present DOE proposals to fund carbon capture and storage projects.

The originally proposed cost in 2003 was \$1.5 billion. In December, 2008, the cost was given as \$1.8 billion.

Other Energy Resources

- Have long-term resources of fuels that are difficult and uneconomic to use
 - coal, oil shale, tar sands
- Need transportation liquid transportation fuels and gaseous fuels for home heating and industrial processes
- Can fuel conversion processes improve environmental impact of fuel use?

Estimates of resources (not reserves) are always questionable. However worldwide resource estimates of coal are typically around 150,000 quads; worldwide resource estimates for oil shale, and tar sands (oil sands) are about 14,000 quads each. These estimates compare with about 4,500 quads each for oil and natural gas. Although coal has been a major fuel in electric power production and some industrial processes, the use of coal and resources such as oil shale for transportation and domestic users will require some of the kinds of processing discussed here.

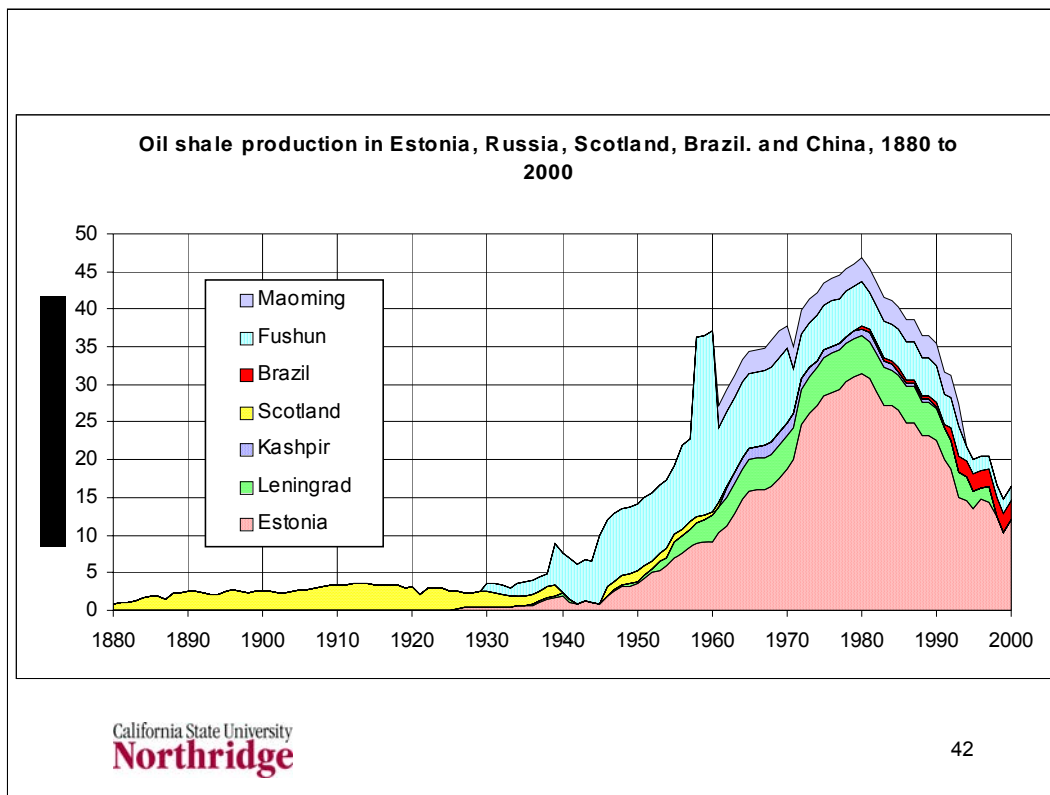
Oil Shale

- Neither oil nor shale
 - Rock (organic marlstone) whose petroleum-like content is called kerogen
 - kerogen must be heated to form petroleum
 - Heating produces greater volume of waste than original mined ore
 - Resulting product has greater sulfur and nitrogen concentrations compared to oil

Reference: http://hubbert.mines.edu/news/Youngquist_98-4.pdf (Accessed April 5, 2008)

The U. S. Geological Survey (USGS) defines oil shale as "organic-rich shale that yields substantial quantities of oil by conventional methods of destructive distillation of the contained organic matter, which employ low confining pressures in a closed retort system." (Duncan and Swanson, 1965). They further define oil shale for purposes of their report to "any part of an organic-rich shale deposit that yields at least 10 gallons (3.8 percent) of oil per short ton of shale..."

Organic-rich shales which would qualify as oil shales by the USGS definition exist in the geological column from Cambrian deposits formed more than 500 million years ago, to Tertiary deposits formed within the last 70 million years. They can form in shallow marine embayments or in lakes, ponds, and swamps. Grades of these deposits may range up to more than 100 gallons of oil per ton, although this is quite exceptional. Most average less than 40 gallons a ton.



Reference: <http://www.emdaapg.org/Oil%20Shale.htm>

Swedish alum shale of Cambrian and Ordovician age, which is noted for its alum content and high concentrations of metals including uranium and vanadium, have been used as early as 1637, to extract potassium aluminum sulfate. Late in the 1800s, the alum shales were retorted on a small scale for hydrocarbons. Production continued through World War II but ceased in 1966 because of the availability of cheaper supplies of petroleum crude oil.

An oil shale deposit at Autun, France, was exploited commercially as early as 1839. The Scottish oil shale industry began about 1859, and by 1881 oil shale production had reached one million metric tons per year. With the exception of the World War II years, between 1 and 4 million metric tons of oil shale were mined yearly in Scotland from 1881 to 1955 when production began to decline, then ceased in 1962. Canada produced some shale oil from deposits in New Brunswick and Ontario in the mid-1800s.

Several oil shale leases on Federal lands in Colorado and Utah were issued to private companies in the 1970s. Large-scale mine facilities were developed on the properties and experimental underground "modified in situ" retorting was carried out on one of the lease tracts. However, all work has ceased and the leases have been relinquished to the Federal Government. Unocal operated the last large-scale experimental mining and retorting facility in western United States from 1980 until its closure in 1991. Unocal produced 4.5 million barrels of oil from oil shale averaging 34 gallons of shale oil per ton of rock over the life of the project.

Tar Sands (Oil Sands)

- Deposits of bitumen, a heavy black viscous oil upgraded to crude oil
- Main sources are in Alberta, Canada and Venezuela
- Alberta oil sands have 10-12% bitumen, 80-85% mineral matter, and 4-6% water
- In 2006 oil sands accounted for 42.9% of Canadian oil production and 14.6% of US plus Canadian production

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Reference: <http://www.energy.gov.ab.ca/News/oilsands.asp> (Accessed April 5, 2008)

Until recently, Alberta's bitumen deposits were known as tar sands but are now referred to as oil sands. Bitumen is best described as a thick, sticky form of crude oil, so heavy and viscous that it will not flow unless heated or diluted with lighter hydrocarbons. At room temperature, it is much like cold molasses. It requires dilution with lighter hydrocarbons to make it transportable by pipelines.

Oil sands are substantially heavier than other crude oils. Technically speaking, bitumen is a tar-like mixture of petroleum hydrocarbons with a density greater than 960 kg/m^3 ; light crude oil, by comparison, has a density as low as 793 kg/m^3 .

Compared to conventional crude oil, bitumen requires some additional upgrading before it can be refined. Bitumen makes up about 10-12 per cent of the actual oil sands found in Alberta. The remainder is 80-85 per cent mineral matter – including sand and clays – and 4-6 per cent water.

Oil sands are found in three places in Alberta – the Athabasca, Peace River and Cold Lake regions – and cover a total of nearly 141,000 square kilometers. In 2006 Canada produced 2.643 million barrels per day (MMBPD) of which 1.133 MMBPD (42.9%) came from oil sands. This compares to the 2006 US production and consumption of 5.102 MMBPD and 20.698 MMBPD respectively. Data from EIA web site accessed April 5, 2008.

Mineable bitumen deposits are located near the surface and can be recovered by open-pit mining techniques. About two tonnes of oil sands must be dug up, moved and processed to produce one barrel of oil. Roughly 75 per cent of the bitumen can be recovered from sand; processed sand has to be returned to the pit and the site reclaimed.

In situ recovery is used for bitumen deposits buried too deeply – more than 75 meters – for mining to be practical. Most in situ bitumen and heavy oil production comes from deposits buried more than 400 meters below the surface of the earth.

Cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD) are in situ recovery methods, which include thermal injection through vertical or horizontal wells, solvent injection and CO_2 methods. Canada's largest in situ bitumen recovery project is at Cold Lake, where deposits are heated by steam injection to bring bitumen to the surface, then diluted with condensate for shipping by pipelines.